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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY

OF

JUSTIN R. BARNES

ON BEHALF OF

SUNRUN, INC.

DECEMBER 11, 2015

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION.

A. Justin R. Barnes, 401 Harrison Oaks Blvd Suite 100, Cary, North Carolina, 27513. My current position is Director of Research with EQ Research LLC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years, where I worked on the *Database of State Incentives for Renewables and Efficiency (DSIRE)* project, and several other projects related to state renewable energy and efficiency policy.

In my current position I coordinate EQ Research's various research projects for clients, directly manage and perform research for a solar energy regulatory policy tracking service, contribute as a researcher to other standard policy service offerings, and perform customized research. I have testified before the Public Service Commission of South Carolina and the Oklahoma Corporation Commission as an expert in distributed generation and net metering policy. My *curriculum vitae* is attached as Exhibit JRB-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS ("PUCT" OR "COMMISSION")?

A. No.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Sunrun, Inc. Sunrun is the largest dedicated residential rooftop solar company in the United States. The company designs, installs, monitors and maintains solar panels on homeowner rooftops. Sunrun's wholly-owned subsidiary, AEE Solar, distributes solar power products to dozens of solar installers across Texas, including three companies doing business in EPE's service territory. Sunrun seeks to expand its operations in the rooftop solar market and is concerned that a decision approving the proposed partial requirements tariff will inhibit the growth of a private marketplace for distributed rooftop solar and other distributed energy resources ("DERs") in the state.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the deficiencies in the application of the El Paso Electric Company ("EPE" or "the utility") to establish a separate partial requirements rate class for residential customers with distributed generation ("DG customers"), and subject those customers to rates with a higher fixed charge and demand components. More specifically, I discuss:

1. The fatal flaws in EPE's analysis and conclusion that residential DG customers should be considered a separate class of customer;
2. How EPE has failed to show that residential DG customers are being subsidized by other non-DG customers;
3. How EPE has failed to consider the long-term value of DG resources in attempting to justify the revised rates for DG customers;
4. Why EPE's proposed partial requirements rate is out of step with traditional ratemaking principles; and
5. Alternative rate designs that could be used to address the purported "subsidy" that EPE alleges current rates provide to DG customers.

Based on this discussion I recommend that the Commission reject EPE's partial requirements tariff proposal. I also suggest how the PUCT should assess any future proposals of this type.

II. EPE'S PROPOSED PARTIAL REQUIREMENTS TARIFF PROPOSAL

Q. WHAT IS THE DEFINITION OF A PARTIAL REQUIREMENTS CUSTOMER IN EPE'S PROPOSAL?

A. EPE defines a partial requirements customer to be a retail electric customer that uses on-site renewable generation to serve a portion of the customer's electric needs. The on-site generation is designed to operate on the customer's side of the electric meter, so that it provides energy first to the customer, and any excess generation to EPE. The proposed tariff itself is provided in Schedule Q-8.8 of EPE's application, listed as Schedule No. 3 Residential Partial Requirements Service Rate ("DG rate" or "partial requirements rate").

Q. PLEASE DESCRIBE THE RATE SCHEDULE THAT EPE PROPOSES FOR PARTIAL REQUIREMENTS CUSTOMERS?

A. The proposed rate includes a fixed monthly charge of $15/month. It would also impose mandatory demand charges on DG customers under two different customer options. The first option sets the demand rate at $3.89/kilowatt ("kW") of demand during all times of the year. The second option contains a summer seasonal demand charge of $11.75/kW for the months of May through October, and a winter seasonal demand charge of $3.89/kW from November through April. The demand charges are based on non-coincident peak usage measured over a 60-minute time period.[1] In other words, the demand charges are disconnected from metered use at the time of system peak, which is the primary driver of generation, transmission, and many distribution system costs. The first rate option is accompanied by a slightly inclining tiered energy charge during the summer

[1] *See* EPE Response to Sunrun RFI 2-33.

period. The second option contains time-of-use ("TOU") energy charges during the summer on-peak period of 12 – 8 PM.

Q. HOW DO EPE'S PROPOSED DG RATES DIFFER FROM THE RATES EPE PROPOSES FOR OTHER RESIDENTIAL CUSTOMERS?

A. They differ in several ways. First, the fixed charge under the partial requirements rate is $5/month higher than what EPE proposes for the standard residential rate schedule (Schedule No. 1). Second, the DG rate contains mandatory demand rates while Schedule No. 1 does not. Third, the energy charges under the partial requirements rate are dramatically lower than those proposed under the standard residential rate. For instance, the rates under the non-TOU partial requirements rate are roughly 3.4 cents/kWh lower than the standard residential rate. The difference in the TOU rates is far more dramatic. The on-peak rate is roughly 11.5 cents/kWh lower and the off-peak rate is roughly 5.1 cents/kWh lower under the partial requirements rate. In fact, the off-peak rate under TOU partial requirements rate is virtually non-existent at roughly 0.2 cents/kWh during summer off-peak periods and the winter months. Ultimately, the rates are designed to recover a very high percentage of all utility costs through fixed and demand charges.

Q. DOES EPE PROPOSE TO SUBJECT NON-RESIDENTIAL DG CUSTOMERS TO SEPARATE RATES?

A. No. EPE's partial requirements rate proposal is confined to residential DG customers. The utility does not propose different rates for DG customers in non-residential customer classes such as general service customers.

III. EPE'S ANALYSIS SHOWS THAT DG CUSTOMER USAGE PATTERNS ARE SIMILAR TO THOSE OF OTHER RESIDENTIAL CUSTOMERS

Q. ON WHAT BASIS DOES EPE JUSTIFY SUBJECTING DG CUSTOMERS TO SEPARATE RATES?

A. EPE Witness Schichtl testifies that the existing residential rate does not account for the variations in usage between DG customers and non-DG customers, such that the standard residential rates do not accurately reflect the costs that DG customers impose or do not impose on the system.[2] Mr. Schichtl bases this on an analysis of DG customer consumption patterns for 36 solar DG customers, which is described in the testimony of EPE Witness Novela and accompanying Exhibit GN-7. The collective argument of Mr. Schichtl and Mr. Novela is that DG customer usage patterns fall outside of those that are typical of the residential class of customers as a whole, and that these "partial requirements" customers therefore constitute a separate class of customer that should be subject to a different rate design.

More specifically, based on Exhibit GN-7, EPE argues that in terms of total household energy needs—the total of energy supplied by EPE plus energy supplied by DG—residential DG customers are on the higher end of the residential usage spectrum, and are most similar to customers that consume from 801 – 1,400 kWh on a monthly basis. This is referred to as Strata 4 in the utility's load research study, the second highest residential usage strata.

The comparison is represented in Figures 3 and 4 in Exhibit GN-7, comparing Strata 4 customers to total DG household patterns in terms of energy consumption, maximum demand and coincident demand. The utility then provides data showing that the contribution of DG energy production to a customer's load results in billed usage of 26% less than a Strata 4 customer.[3] It also provides data comparing maximum demand and coincident demand of Strata 4 customers with DG customers in terms of delivered demand.[4]

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[2] Schichtl Direct, p. 33 lines 1-3.
[3] EPE Exhibit RN-7, p. 4 and Figure 5.
[4] EPE Exhibit RN-7, Figure 6.

Q. IS EPE CORRECT THAT RESIDENTIAL DG CUSTOMERS CONSTITUTE A SEPARATE CLASS OF RESIDENTIAL CUSTOMER WITH DISTINCTIVE USAGE PATTERNS?

A. No. EPE's own, though limited, analysis shows that residential DG customers remain well within the diversity of usage that exists within the residential class as a whole, which as Mr. Schichtl observes, "includes customers with a wide range of consumption characteristics."[5] EPE only reaches its conclusion by cherry-picking the data and making inapt comparisons in order to support its preferred outcome. As I related previously, EPE's analysis shows that "before" DG, DG customers are similar to relatively high usage Strata 4 customers. With the installation of DG they are more similar to moderate usage customers that fall within Strata 3. Furthermore, the underlying data used in the assessment shows that "after" DG, DG customers continue to occupy a wide range in the spectrum of residential customers, with wide-ranging monthly consumption, demands, load factors, and coincidence factors.[6]

Q. YOU REFERRED TO EPE'S ANALYSIS AS "LIMITED" IN YOUR PREVIOUS RESPONSE. WHAT DO YOU MEAN BY THIS AND HOW DOES THAT AFFECT YOUR OPINION OF THE ANALYSIS?

A. EPE's analysis is based on a sample size of 36 residential solar DG customers, and covers a time period of only one year. This is not a large sample size by any measure and the analysis covers only the shortest possible time period (one year), from April 2014 – March 2015. I do not question the sampling methodology itself, but I do think the limited data set raises questions as to its accuracy for representing DG customers as a whole.

In fact, the underlying data shows at least one aberration that has a meaningful impact on the DG load shapes identified in EPE Exhibit RN-7. During March 2015 the data shows a maximum demand of 18.03 kW and energy

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[5] Schichtl Direct, p. 25, lines 16-17.
[6] EPE Response to Sunrun RFI 2-2, Attachment 2-002, included as Exhibit JRB-2.

consumption of 1,653 kWh for the Strata 4 group of customers. The maximum demand value is more than 2.3 times the maximum demand of any other DG customer strata in any other month, while the energy consumption value is markedly higher than one would expect during March and out of step with the values for any other strata of customers during that month.[7] This unexplained variation creates a visible effect in EPE Exhibit RN-7 Figures 2, 4, and 6. While I do not suggest that this particular data point is the driving force behind EPE's conclusions, I am concerned that other, less visible aberrations could be affecting the data in a meaningful way.

Q. PLEASE DESCRIBE THE PROBLEMS YOU SEE IN THE FRAMEWORK THAT EPE APPLIED TO ITS CUSTOMER USAGE PATTERN ANALYSIS?

A. EPE's conclusion hinges on the assumption that total household energy use and demand—the combination of electricity supplied by EPE and that supplied by DG—is somehow relevant to a determination of whether DG customers constitute a separate class of customers. This is a red-herring intended to create the misleading justification for assessing DG customer usage patterns against Strata 4 customer usage patterns. From a cost of service perspective, total DG household consumption patterns are irrelevant. This approach ignores the effects that the DG system has on the cost to serve that customer.

Any customer can make investments or behavioral changes that substantially modify their usage patterns. These changes do not necessarily involve the installation of DG. They could be investments in efficient appliances, changes made to programmable thermostat settings, or many other actions. Yet rates for these customers are not modified to reflect the former level of usage. Cost of service reflects the actual amount of power drawn from the utility system at different times, not a hypothetical "what if" scenario.

[7] *See* Exhibit JRB-2, p. 2 showing partial requirements class cost allocation determinants.

Q. ENERGY EFFICIENT APPLIANCES CONSUME LESS ENERGY AND PLACE LOWER DEMANDS ON THE SYSTEM WHILE DG SYSTEMS GENERATE ENERGY. DOES THIS NOT DISTINGUISH ENERGY EFFICIENCY MEASURES FROM DG?

A. The method by which DG affects a customer's demand for electricity from the grid is different than improved efficiency, but the practical effect on the system is the same, a reduction in use, accompanied by a corresponding reduction in the customer's energy bill.

Q. HAS EPE ANALYZED HOW THE ADOPTION OF ENERGY EFFICIENCY MEASURES OR OTHER TECHNOLOGIES AFFECT THE COST TO SERVE CUSTOMERS OR WHETHER THIS WOULD RESULT IN COST SHIFTS?

A. To my knowledge it has not done so. Mr. Schichtl has stated that EPE does not track participation in energy efficiency programs on a per customer basis.[8] Without this data, it does not appear to me that an analysis similar to what it has performed for solar DG customers would be possible. Moreover, it makes it impossible to determine how the load patterns of DG customers are influenced by the adoption of energy efficiency measures and how that might impact the DG analysis.

Q. IS ENERGY EFFICIENCY MORE DISPATCHABLE OR RELIABLE THAN DG?

A. Under most circumstances neither is dispatchable. This characteristic would only be present for energy efficient appliances if they are equipped with devices that allow such control, such as remote-operated air conditioner cycling equipment, or battery storage for DG. However, both could still be considered reliable in providing sizable reductions in peak demand. For solar DG, this is evidenced by EPE's own data, as summarized in Figure 6 of EPE Exhibit RN-7. To my

[8] EPE Response to Sunrun RFI 1-26, included as Exhibit JRB-3.

knowledge EPE has not provided a similar analysis for energy efficiency measures in its rate case application, though I assume that it has probably done so for use in other proceedings.

Q. EVEN IF ONE WERE TO ASSUME THAT EPE APPLIED A REASONABLE ANALYTICAL FRAMEWORK, IS EPE'S CONCLUSION ACCURATE?

A. No. EPE's analysis in fact shows that DG customers are different from Strata 4 customers if the impacts of DG are considered, as they should be. DG customers have lower delivered energy requirements, substantially lower maximum demands during June and July (with smaller differences in other months) and substantially lower coincident demands during the majority of months of the year, including summer.[9] Both Mr. Schichtl and Mr. Novela acknowledge these differences in coincident demand and delivered energy, though they minimize the differences in maximum demand.[10] [11] Ultimately, EPE's evaluation is less an analysis than an effort to define an outcome, selectively present data to support that outcome, and ignore or diminish findings that do not support it.

Q. WHAT TYPE OF EVALUATION WOULD EPE NEED TO PERFORM IN ORDER TO JUSTIFY PLACING DG CUSTOMERS IN A SEPARATE CLASS?

A. EPE would need to perform an analysis showing that the *actual* cost to serve residential DG customers (i.e., after the installation of DG) is substantially different than that of other residential customers. Moreover, in order to justify the dramatic change in rate structure that it proposes, the utility must show that the current rate structure is inadequate to recover the cost to serve these customers. In other words, the utility must show that cost to serve residential DG customers is

[9] EPE Exhibit RN-7, Figure 6.
[10] Schichtl Direct, p. 32, lines 2-12.
[11] EPE Exhibit RN-7, p. 5.

higher than what can typically be recovered through the existing, established rate structure. EPE has made no such showing in this case.

Q. PLEASE SUMMARIZE WHY EPE EXHIBIT RN-7 FAILS TO SUPPORT THE ESTABLISHMENT OF A SEPARATE CLASS FOR DG CUSTOMERS?

A. Exhibit RN-7 shows that residential DG customers on average use less energy and have lower summer maximum and coincident peak demands than Strata 4 customers during 2014-2015. During the winter months the two groups are fairly similar, and apart from the March 2015 aberration that I have described previously. This shows that the actual loads of DG customers clearly fall within the load diversity of the residential class, and in fact within the median Strata 3 group. It also shows that DG customers are less costly to serve than Strata 4 customers due to their lower energy consumption during summer months and lower summer maximum and coincident demands. Again, this is what would be expected for Strata 3 customers, which exist in the middle of the usage spectrum.

As I discuss in the following section, EPE's analysis does not address what the average cost to serve residential DG customers is, or what they pay towards this cost of service. In this respect, it does not identify any cost shift or subsidy that merits mitigation, much less one that could justify the creation of separate customer class and a radical change in rate structure.

IV. EPE DOES NOT DEMONSTRATE THAT DG CUSTOMERS FAIL TO PAY THE COST OF SERVING THEM

Q. WHY IS THE ANALYSIS OF DG CUSTOMER COST OF SERVICE AND THE BENEFITS OF DG IMPORTANT IN SETTING RATE DESIGNS FOR DG CUSTOMERS?

A. Mr. Schichtl states that EPE's proposed DG rate reforms are intended to "allow partial requirements customers to receive the full value of their DG system and limit inter- and intra-class subsidies".[12] Logically, getting to this outcome requires an analysis of what that "full value" actually is, and at what level DG customers contribute to their cost of service under different designs. In considering whether rate reforms for DG customers are needed, it is necessary to first answer the question of whether DG customers pay their cost of service under current rates. This is a holistic question that addresses the appropriateness of a rate structure on average and as a whole, not each individual element of that rate structure. Secondarily, if a cost of service "gap" is found to exist, it is also necessary to discover whether long-term benefits from DG on the system exceed the amount of that identified gap because these benefits ultimately accrue to other customers (i.e., reduce or eliminate a perceived short-term subsidy).

Q. HAS EPE CONDUCTED THE TYPE OF ANALYSIS YOU HAVE JUST DESCRIBED?

A. No. EPE has made not made any effort to figure out whether any cost of service gap exists. It simply pre-supposes that a subsidy exists and provides a tenuous and unconvincing analysis to support its conclusion that residential DG customers should be considered a separate class subject to a separate rate structure.

Q. PLEASE ELABORATE ON HOW A DG COST OF SERVICE STUDY SHOULD BE USED IN DETERMINING THE NEED FOR POTENTIAL RATE REFORMS.

A. EPE's partial requirements rate proposal is based on the supposition that DG customers are being subsidized by other customers. Utilities, like EPE, are prone to assuming that such a subsidy is an unavoidable effect of net metering, but the question of whether DG customers pay their full cost of service requires actual analysis. While it is true that DG customers do pay lower bills to the utility after installing DG, they still make significant payments to the utility during many months of the year. EPE's analysis shows that residential DG customers tend to

[12] Schichtl Direct, p. 31, lines 6-7.

remain at the higher end of residential usage spectrum in terms of utility deliveries of electricity even after the installation of DG.[13] Thus they still make substantial payments to the utility in return for service.

Moreover, since solar DG in particular tends to reduce the customer's contribution to peak demand, there is the distinct possibility that the cost to serve DG customers as a whole is lower than that required to serve many other customers in the same class. For instance, EPE's own analysis shows that relative to above average users, DG customers have modestly lower maximum peak demands and dramatically lower coincident peak demands during the summer months.[14]

Thus avoided payments do not automatically equate to failure to cover cost of service. Given that residential DG customers in EPE's territory still remain above average customers even after the installation of DG, it is entirely plausible that they continue to pay *above* their cost of service under current rates. Discovering whether this is true, and the magnitude of any surplus or gap requires an analysis to determine the actual cost to serve DG customers, and what they pay as a group towards this cost.

Q. IS THE IDENTIFICATION OF WHAT YOU REFER TO AS A COST OF SERVICE "GAP" DETERMINATIVE THAT A SUBSIDY EXISTS AND THAT RATE REFORMS ARE WARRANTED?

A. Not necessarily. It only raises the possibility that rate reforms *could be* warranted. I say "could be" for two reasons. First, it is an undeniable fact that subsidies will always exist to some degree in utility rates. Rates are necessarily inexact in this respect so there is a policy decision to be made as to whether the magnitude of any potential subsidy merits action. This is a qualitative question that requires consideration of a number of factors, not the least of which is whether a supposed solution would only introduce a different variety of subsidy.

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[13] EPE Exhibit RN-7, p. 4.
[14] EPE Exhibit RN-7, p. 5.

Second, a cost of service analysis suffers from several meaningful limitations that render it incapable of determining whether DG customers are a *net* cost to other customers. As I describe later in my testimony, a cost of service study fails to capture long-term costs and benefits that vary with time, as well as electricity system benefits that are difficult to quantify. What this means in practice is that any identified gap may in the long run be exceeded by the value of DG to the electric system as a whole, rendering the perceived subsidy imaginary.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT EPE'S COST OF SERVICE STUDY AND PROPOSED RATE DESIGN?

A. Yes. Mr. Schichtl justifies increasing the monthly fixed charge on DG customers relative to other residential customers by stating that the bi-directional metering required for net metering customers carries additional costs.[15] Yet the associated cost of service study fails to provide any meaningful details on how this estimate was derived, and ultimately how this conclusion was reached. Moreover, if there are verifiable additional metering costs for net metering customers it makes more sense for these to be paid by the customer as a one-time fee for the incremental metering costs, not a monthly assessment that will, over time, likely charge these customers far in excess of the incremental costs. As proposed, the additional charge would amount to $1,500 over the course of 25 years for a DG customer, which is surely far in excess of the incremental cost of a bi-directional meter.

V. EPE'S APPLICATION DOES NOT CONSIDER THE FULL VALUE THAT DG RESOURCES PROVIDE TO THE SYSTEM

Q. HOW HAVE OTHER STATES ADDRESSED THE QUESTION OF DG VALUE AND POTENTIAL DG RATE REFORMS?

A. States have typically undertaken investigations and studies of DG value as a precursor to considering rate changes for DG customers. Most of these states have

[15] Schichtl Direct, p. 34, lines 6-13.

approached the topic from the perspective of the relative costs and benefits of DG or the policy of net metering. This framework is based on a rationale that if DG or net-metered installations yield long-term benefits that exceed the costs, non-participating ratepayers ultimately benefit from their deployment. In other words, if the long-term costs avoided by DG exceed the compensation provided to DG customers (e.g., retail rate compensation under net metering), there is no subsidy being provided by non-DG customers to DG customers. Reversing the logic, if rate changes that discourage DG deployment are implemented, the long-run benefits will be reduced, resulting in a net cost to ratepayers. These studies and investigations have arisen for different specific reasons (e.g., legislative requirements, utility rate requests) but at the most basic level they are efforts to better understand the relative costs and benefits of DG *prior* to pursuing rate reforms.

Q. WHERE HAVE THESE INVESTIGATIONS TAKEN PLACE, AND WHAT FINDINGS HAVE THEY MADE?

A. Quantitative cost-benefit studies have been completed in many states, including California, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, Nevada, and Vermont. Investigatory proceedings are ongoing in Arizona, New York, Oregon, and Utah. The Colorado Public Utilities Commission also recently concluded an investigation into similar issues, though it did not conduct a formal quantitative study. Several of the completed studies were preceded by or involved regulatory proceedings intended to elicit stakeholder input on the appropriate cost-benefit methodology (e.g., in Maine and Minnesota) prior to the completion of the study. The ongoing proceedings in New York, Oregon and Utah are likewise devoted to this purpose.

In terms of findings, in most cases the studies have found net metering or DG to have long-term net benefits, typified by an estimate of long-term DG value that exceeds retail electricity rates. As yet, none of the studies have resulted in changes to net metering or to rates for DG or net metering customers, though both

California and Nevada remain engaged in regulatory proceedings that could modify net metering rate design as a result of separate legislative requirements. Exhibit JRB-4 summarizes the findings of recent DG value studies completed by or on behalf of state regulatory agencies, as well as investigations that remain ongoing or have not resulted in quantitative studies.

Q. WHAT SORTS OF SPECIFIC LONG-TERM BENEFITS CAN DG PROVIDE?

A. The Interstate Renewable Energy Council ("IREC") has published a guidebook for regulators on the topic of DG cost-benefit studies. This publication, which was co-authored by a former Commissioner with the PUCT and utility executive, provides an excellent qualitative description of a thorough DG cost-benefit methodology, the relevant cost-benefit components, and the different ways that values may be calculated for these components.[16] The guidebook includes the following analytical categories:

- Avoided energy
- Avoided generating capacity
- Avoided line losses (reflected in avoided energy and capacity values)
- Avoided transmission and distribution capacity and/or deferral of associated upgrades
- Grid support and ancillary services
- Reduction in fuel price risk (i.e., power plant fuel price hedge)
- Electricity market price effects (i.e., reduction in wholesale power prices)
- Grid security, reliability and resiliency services
- Environmental benefits (i.e., avoided compliance and societal costs)
- Local economic development

[16] IREC. *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* October 2013. http://www.irecusa.org/a-regulators-guidebook-calculating-the-benefits-and-costs-of-distributed-solar-generation/

Q. HAS EPE PROVIDED ANY ANALYSIS OF THE BENEFITS OF DG IN ITS RATE PROPOSAL?

A. No. The only reference to anything that might be seen as an assessment of the value of DG is the determination of the generation rate credit, which is applied to monthly excess generation supplied to the distribution system by net-metered customers. This credit is what Mr. Schichtl describes as the "current market generation value of renewable energy", represented by the levelized cost of energy ("LCOE") of generation from a proposed, EPE-owned, 3 MW community solar facility.[17]

Q. IS THIS PURPORTED "MARKET VALUE" REPRESENTATIVE OF THE FULL SUITE OF LONG-TERM BENEFITS THAT DG ON A UTILITY SYSTEM CAN PROVIDE?

A. No. While in some contexts, avoided costs are equivalent to value, in this instance the LCOE of energy bears no relationship to the value of the services provided by the community solar facility. Moreover, the proposed facility itself is not comparable to customer-sited DG in terms of costs and value. The differences between the two are considerable. For instance, customer-sited DG installations carry additional benefits, such as reduced system load, that a grid-supply facility does not.

Q. HOW DOES EPE USE THIS PURPORTED "VALUE" IN DETERMINING ITS PROPOSED DG RATES, AND HOW DOES THIS AFFECT DG CUSTOMER RATES?

A. EPE reflects the generation credit as a reduction in the revenue requirement for the partial requirements class, applying in such way that it reduces the energy charges in partial requirements customer rates. However, as Mr. Schichtl describes, due to the class rate increase capping methodology EPE is employing

[17] Schichtl Direct, p. 36, lines 9-12.

the credit is not sufficient to bring the revenue requirement below the capped revenue level.[18] Thus the partial requirements class does not actually receive a benefit from the credit because it is not subtracted from revenue requirement after the cap is applied. Even if it were applied to the capped revenue, the credit would only serve to depress volumetric rates further and ultimately diminish a customer's incentive to pursue DG. This is another example of how EPE's proposed rate design fails to reflect the value of having DG on the utility system in its proposed partial requirements customer rates.

Q. HAS THE CONCEPT OF DG VALUE PLAYED A ROLE IN RATEMAKING DECISIONS MADE IN OTHER STATES?

A. Yes. In 2014 the Utah Public Service Commission rejected a proposal by Rocky Mountain Power, the state's largest utility, to subject DG customers to an additional fixed charge. It did so because the utility failed to adequately consider the benefits of DG, and failed to provide evidence that DG customers do not pay their full cost of service. The Utah Public Service Commission found that the fact that net metering customers use less electricity on average does not alone justify an additional charge.[19] Moreover, it also found that the record before it did not contain a comprehensive view of net metering costs and cost savings (i.e., benefits) on which to base a decision.[20]

In another example, in October 2015 the Dane County Circuit Court reversed a prior decision by the Wisconsin Public Service Commission approving a capacity-based surcharge on DG customers of We Energies. This decision was similarly based on the presiding judge's determination that the utility had failed to provide sufficient evidence to establish that a subsidy from non-DG customers to

[18] Schichtl Direct, p. 36, lines 13-15.
[19] "In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," Utah Public Service Commission Docket No. 13-035-184, Report and Order of Aug. 29, 2014 at p. 62.
[20] Ibid at p. 66.

DG customers exists, and that the Commission failed to consider the long-term costs avoided by DG. For instance, the presiding judge stated:

> “the idea that this class of customers is different from every other user who uses less than average has not yet been credibly asserted to me in this court or in this record or even mentioned in the commission's decision. So I think, if they are going to go back and do that, they should address that issue in good faith: Why is it we're thinking these folks are different from somebody that puts in an energy-efficient refrigerator? [21]

Q. ARE THE LONG-TERM BENEFITS OF DG REFLECTED IN ANY WAY IN EPE’S DG TARIFF RATE PROPOSAL?

A. A small number of the benefits are reflected implicitly in EPE’s cost allocation structure for the tariff, but the utility fails to address the full suite of benefits. Short-term avoided energy benefits are reflected in the volumetric pricing of the tariff, though the flat rate option disregards the higher value that near or on-peak energy production would have, and the wide TOU rate window (12 – 8 PM) does not reflect DG’s contribution to the highest, critical peaks that may occur during a far more limited set of hours. The volumetric portion of the partial requirements rate would presumably include compliance costs for pollutant emissions. It is not clear to me that the rates reflect any capacity value for DG resources, even for production demands driven by system coincident peak demand.

Q. PLEASE ELABORATE ON WHY THIS INDIRECT ASSESSMENT OF DG BENEFITS IS INCOMPLETE.

A. There are three major deficiencies in this type of assessment. First, as I have already discussed, EPE has made no attempt to identify whether a cost of service

[21] Dane County Circuit Court. *The Alliance for Solar Choice and Renew Wisconsin vs. Public Service Commission of Wisconsin.* Case No. 15CV153. October 30, 2015. Bench ruling of Judge Peter C. Anderson. p. 69, lines 7-16.

gap exists in the first place, and how its proposed DG tariff would affect or change this gap. The utility's proposed tariff is effectively based on correcting a subsidy that may not even exist, and potentially over-correcting even if it does.

Second, the analysis utilizes only a short-term outlook. The reality is that DG will contribute to cost avoidance throughout the life of the DG system, which is likely to be 25 years or more. Designing rates that are intended to address a purported subsidy requires an analysis that uses a long-term perspective because a fundamental change in rate design is a *long-term* policy decision. A limited short-term assessment risks a decision that is penny wise and pound foolish, shortchanging the long-term interests ratepayers have in avoiding future costs.

Third, though tied to my second criticism, this assessment ignores a large number of near and long-term system benefits supplied by DG. For instance, DG exports will physically displace central station power on a given circuit, resulting in lower marginal line losses, which would be highest at peak times. Furthermore, in this instance, the value of that exported generation on a monthly basis is credited to the customer at a wholesale rate that does not reflect its true value.

Demand reductions from DG that coincide with cost causing conditions (e.g., circuit or system peaks) allow for the deferral of generation, transmission and distribution capacity investments by the utility. These are long-term, incremental effects, but they are nevertheless a source of value because avoided or deferred utility investments are costs that customers no longer have to pay or can pay at a later date. Finally, the assessment does not consider a series of future effects, such as a reduction in power plant fuel prices or purchased power price risk.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ON EPE'S ASSESSMENT OF THE COST TO SERVE DG CUSTOMERS AND THE VALUE OF DG.

A. The critical flaws in EPE's analyses are: (1) The utility never directly evaluated the cost to serve DG customers and whether they currently pay their cost of service, and (2) it failed to perform any analysis of long-term benefits to discover whether any identified cost of service gap is offset by other values supplied to the system. As a result of these deficiencies, there is no credible evidence indicating that residential DG customers do not currently pay their cost of service, or are otherwise being subsidized by other customers. EPE's proposed partial requirements tariff, which is itself a poor fit for residential customers, is a solution in search of a problem.

VI. EPE'S PROPOSED RATE DESIGN IS DISCRIMINATORY AND OUT OF STEP WITH TRADITIONAL RATEMAKING PRINCPLES

A. Principles for establishing just and reasonable rates

Q. WHAT ARE THE GENERAL REQUIREMENTS FOR THE ESTABLISHMENT OF UTILITY RATES IN TEXAS?

A. Texas law sets a "just and reasonable" standard for utility rates, and states that "A rate may not be unreasonably preferential, prejudicial, or discriminatory but must be sufficient, equitable, and consistent in application to each class of consumer."[22] The law goes on to prohibit a utility from establishing or maintaining "an unreasonable difference concerning rates between localities or between classes of service."[23] The burden for proving that rate changes are just and reasonable falls on the utility.[24]

Q. WHAT IS THE MEANING OF "JUST AND REASONABLE" IN THIS CONTEXT?

A. There is no single accepted definition of this term that I am aware of. However the oft-cited work of Dr. James Bonbright offers valuable guidance on the criteria that should be used in the development of a sound rate structure, listing a set of

[22] Tex. Utilities Code § 36.003(b)
[23] Tex. Utilities Code § 36.003(c)(3)
[24] Tex. Utilities Code § 36.006

eight principles to consider. I have paraphrased those principles that I believe are most relevant to this proceeding below:

1. The "practical" attributes of simplicity, understandability, public acceptability and feasibility of application.
2. Effectiveness in yielding total revenue requirements under the fair return standard.
3. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
4. Fairness of the rates in apportioning the total cost of service among different consumers.
5. Avoidance of undue discrimination.
6. Efficiency of the rate classes and blocks in discouraging wasteful use of service.[25]

It is generally recognized that these principles are sometimes in conflict with one another, such that rate design involves a subjective judgment of how best to balance the competing objectives. Proper rate design is therefore a policy decision on the part of regulators.

Q. WHAT PROBLEMS ARE CAUSED BY EPE'S PROPOSAL TO IMPOSE MANDATORY DEMAND CHARGES ON RESIDENTIAL DG CUSTOMERS?

A. First, as I have previously described, EPE's conclusion that DG customers should be considered a separate class of customer is in error, making the proposal itself discriminatory. Second, the proposed rates violate a number of the ratemaking principles I relate above, including cost causation, simplicity and customer ease of understanding, rate stability, and discouragement of wasteful use of service. The ultimate result of is that the tariff is unduly discriminatory.

[25] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 291.

B. EPE's proposal does not reflect cost causation

Q. HOW IS EPE'S PROPOSAL MISALIGNED WITH COST CAUSATION?

A. Only a small portion of the transmission and distribution system is designed to serve the maximum demand of an individual customer. The bulk of the system is designed to serve the maximum diversified demand of customers on a given circuit, substation, etc., not the sum of the maximum demands of individual customers. The residential class in particular is characterized by diverse, fluctuating loads, which reduce the connection between a customer's maximum demand and cost-causing conditions. Non-coincident demand rates charge customers for costs *caused by coincident demands* on the basis of a customer's *non-coincident or maximum demand*. The further one travels up the system, from secondary distribution to primary distribution, and to transmission and central generation, the greater this departure from cost causation becomes.

Q. IS IT NOT TRUE THAT NON-COINCIDENT DEMAND CHARGES ARE COMMON IN MANY UTILITY TARIFFS?

A. Non-coincident demand charges are only common for classes composed of larger, non-residential customers. For customers in these classes, which tend to have much higher load factors than residential customers, non-coincident demand *may* reasonably approximate a customer's contribution to system costs. For the diverse residential class, they do not, and as a consequence will overcharge these customers for demand-related costs.

Q. DOES EPE'S TOU DEMAND RATE OPTION FOR DG CUSTOMERS REMEDY THE COST CAUSATION ISSUES YOU RAISE?

A. The TOU rate option may offer a small improvement over the flat rate option, but it remains misaligned with cost causation. A solar DG customer is likely to have a maximum demand on cool, cloudy days. Under either rate option, the DG customer would incur a significant demand charge on the days when circuit demand is low. Yet on sunny, hot days with very high demands (i.e., those that drive costs), the solar DG customer's demand is likely to be much lower. EPE's own data shows that the installation of DG provides a meaningful reduction in a customer's coincident peak demand during the summer months.[26] EPE's proposed rate design ignores the capacity contribution made by DG customers on days of truly high demand.

C. EPE's proposal is too complex for residential customers

Q. HOW IS EPE'S DG TARIFF PROPOSAL IN CONFLICT WITH THE PRINCIPLE OF SIMPLICITY AND UNDERSTANDABILITY?

A. Demand rates are wholly unfamiliar to residential customers. EPE does not currently offer even an optional demand rate for residential customers so there is virtually no chance that any residential customer has experience with a demand rate. The conceptual difference between a kW and a kWh is hard for residential customers to grasp, let alone the meaning of a "60-minute average maximum demand," or how each individual electric load contributes to their electric demand.

This lack of understanding leads to a further drawback, the customer's inability to reliably manage electric demand, and their electricity bill. Any customer can be expected to understand that greater use of electric appliances will lead to higher electricity bills. It is far harder for residential customers to understand and manage the coincidence of their use of electric appliances. They simply lack the information and tools to do so. Even a knowledgeable, diligent customer who desires to reduce their electric demand could be saddled with a high electricity bill on the basis of a single lapse in attention during a month. The burden is likely to fall most heavily on families because as difficult as it may be

[26] EPE Exhibit GN-7, p. 5.

for a single person to manage demand in this fashion, it is even harder to manage the actions of other users, including children.

Q. SHOULD THE NEW RATE BE IMPLEMENTED, DOES EPE HAVE ANY PLANS TO MITIGATE THESE ISSUES AND GENERALLY EDUCATE DG CUSTOMERS ON THE NEW STRUCTURE?

A. EPE fully acknowledges that the customers that would be subject to this rate will be totally unfamiliar with it. The utility states that it has not developed educational materials for the proposed rate, has provided nothing beyond the standard rate increase notice to these customers, and is not in possession of any information showing how well residential customers understand demand charges.[27]

D. EPE's proposal would discourage efficient use of electricity

Q. HOW DOES EPE'S DG TARIFF PROPOSAL VIOLATE THE PRINCIPLE OF EFFICIENCY?

A. Demand charges directly and indirectly discourage energy conservation. Directly, the demand component reduces the volumetric components of rates, making energy savings less valuable for the customer. Indirectly, a customer that makes efforts to reduce their electricity bill but sees little change due to high demand charges is likely to conclude that further efforts to invest in energy efficiency or conservation are unattractive. For many residential customers, who lack the ability to understand and manage their electric demand, a demand charge is effectively equivalent to a higher fixed charge. It therefore sends the same inaccurate price signal that a fixed charge sends to the customer, discouraging energy conservation and encouraging wasteful use of resources.

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[27] EPE Response to SEIA RFI 1-3, included as Exhibit JRB-5.

Q. IS THIS OUTCOME ALIGNED WITH THE EPE'S STATED GOALS FOR RATES PROPOSED FOR OTHER CLASSES OF CUSTOMERS?

A. No. EPE states that a number of elements in its rate application are designed to *encourage* energy conservation. For instance, EPE proposes a summer inclining block structure for the residential class as a whole "to encourage energy conservation and energy efficiency measures by residential customers" during periods of relatively higher production costs.[28] It also proposes to eliminate a discount for high monthly consumption from its tariff so as to "provide price signals to encourage conservation during peak months".[29] These stated goals are at odds with its DG tariff proposal, which dramatically reduces the customer incentive for energy conservation by placing a greater emphasis on fixed and demand charges. It is patently discriminatory for EPE to create a new residential class for whom the rates selectively diminish the value of energy efficiency investments.

Q. WOULD THE PROPOSED DEMAND RATES FOR RESIDENTIAL DG CUSTOMERS PROVIDE AN INCENTIVE FOR PEAK DEMAND REDUCTION?

A. No. The proposed rates do not reward reductions in peak demand because they are based on non-coincident demand. While it is plausible that a customer that reduces their non-coincident demand would also incidentally reduce their peak demand, such a result is not guaranteed, nor is the customer provided with the proper incentive (i.e., reward) for doing so. Furthermore, such an indirect outcome would only occur if residential customers had the information and ability to manage their non-coincident electric demand, which they do not.

A non-coincident demand charge could actually contribute to increased on-peak demand if the customer has access to information on their peak demand during a month. For instance, a customer that sees that they had a 7 kW demand

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[28] Schichtl Direct, p. 24, lines 13-17.
[29] Schichtl Direct, p. 28, lines 17-19.

during the early part of a billing period has a much reduced incentive for limiting their demand for the remainder of the billing period because a minimum demand charge has already been locked in and that customer's volumetric rates are substantially lower. Moreover, a residential customer whose maximum demand occurs during off peak times would be encouraged to shift some of that demand to other times of the day, including times when circuit or system demand is peaking, in order to reduce their demand charge.

Q. WOULD THESE SAME DRAWBACKS APPLY TO DEMAND RATES THAT ARE APPLIED ONLY TO DG CUSTOMERS?

A. Yes, they would. There is no basis for assuming that residential DG customers are somehow better equipped to manage their electric *demand* than other residential customers. A customer that installs DG in an effort to manage their energy use is no different than a customer that installs a geothermal heat pump system, additional insulation, or energy efficient lighting. Like these types of energy efficiency improvements, a solar DG system is a low-maintenance improvement that allows customers who are not able or inclined to more actively manage their energy consumption to nevertheless save on energy costs. DG customers rely *passively* on the improvement to produce cost savings. Like any other customer, a DG customer sits at some point on the spectrum of energy management knowledge and ability. The installation of DG does not skew that customer towards one end or the other on this spectrum.

E. EPE's proposal would result in severe rate increases for many customers

Q. HOW DOES EPE'S PROPOSAL VIOLATE THE PRINCIPLE OF RATE STABILITY?

A. EPE's bill impact estimates show that while bill impacts would differ based on customer consumption characteristics, in many cases the change would result in *dramatic* increases in a DG customer's electricity bill. EPE estimates show that at roughly 86% of customers subject to the new partial requirements tariff would likely experience increases in their annual electricity bill, 67% of customers would see an annual bill increase of 25% or more, and roughly 29% of customers are expected to see bill increases of at least 100%. Small percentages of customers could see bill increases exceeding 200% or $500 annually.[30]

Q. YOU NOTE ABOVE THAT BILL IMPACTS WILL VARY CONSIDERABLY AMONG CUSTOMERS THAT WOULD BE SUBJECT TO THE PARTIAL REQUIREMENTS TARIFF. HOW WOULD YOU EXPECT THE IMPACTS OF A NON-COINCIDENT DEMAND CHARGE TO BE DISTRIBUTED AMONG DIFFERENT CUSTOMERS?

A. Generally speaking, a non-coincident demand charge tends to penalize low usage customers, while the effect is reduced for higher usage customers, to the point where in some cases it can result in reduced bills relative to a volumetric rate structure for some high use customers. This effect occurs because low usage customers typically have lower load factors than high usage customers. That is, the ratio of their average demand to their maximum non-coincident demand is typically lower than that of higher users. The results of EPE's DG customer load research study bear this out, showing generally lower load factors for DG customers located in the lower usage strata relative to those in the higher usage strata, and lower than the weighted average class load factor as a whole.[31]

Q. HOW DOES THIS AFFECT THE BILL IMPACTS THAT THE PARTIAL REQUIREMENTS TARIFF WOULD HAVE ON CUSTOMERS WITH DIFFERENT LEVELS OF ENERGY USE?

A. There is no true definition for what constitutes a high usage vs. a low usage customer, but from the perspective of bill impacts one division that can be drawn

[30] EPE Response to Sunrun RFI 2-6 Attachment 1, summing the customers by percentage increase and monetary bill impact. This full data set forms the basis of EPE Exhibit JS-5, though JS-5 provides only limited histogram representations.

[31] *See* Exhibit JRB-2, p. 4, showing load factors for the five strata of customers and the weighted average load factors of customers in the DG load research study.

is between the customers that will experience bill increases versus those that will receive bill decreases. Of the 442 DG customers that EPE analyzes, 64 are expected to experience decreases in their electricity bill and the remaining 378 are expected to experience bill increases. The customers that are expected to see decreases have current average bills of roughly $1,450 annually and the decreases are expected to average roughly $231 annually ($19.25/month). The customers expected to see increases have bills averaging $386 annually and are expected to experience increases averaging $202 annually ($16.83/month).[32]

While this analysis disregards the size of the DG system installed by each customer, and therefore does not show each customers total usage and bill without DG, it strongly suggests that negative impacts will be most severe on low to moderate usage customers (i.e., those with lower bills). In contrast, those customers that are more likely to be high usage customers (i.e., those with higher bills) will experience positive impacts. Thus as one would expect from this rate design, the effect is to reward high usage customers, who are on average likely to be those with larger homes and higher incomes, and punish those with lower usage and likely correspondingly smaller homes and incomes.

Furthermore, it shows that the average increase of roughly $12/month is somewhat misleading because the average includes sizeable bill decreases for a relatively small number of high usage customers. The average increase for customers that will experience increases is $16.83/month, or 40% higher. Again, the detrimental impacts are largest for relative lower usage customers who actually place lower demands and cause lower costs on the system.

Q. HOW DOES THIS COMPARE TO BILL IMPACTS FROM EPE'S PROPOSED STANDARD RESIDENTIAL RATES?

A. Residential customers under standard rates are expected to experience bill increases no greater than 30%, with roughly 90% seeing a bill increase of 20% or

[32] Ibid. Based on sorting and averaging the customer impacts provided in EPE Response to Sunrun 2-6, Attachment 1.

less. In monetary terms, EPE indicates that the maximum bill increase would not exceed $160 annually.[33] Essentially, DG customers would experience both the significant effects of the general rate increase, and an additional, meaningful increase as a result of the proposed change in rate design.

Q. DO OTHER PORTIONS OF EPE'S RATE APPLICATION DISPLAY CONSIDERATION OF THE PRINCIPLE OF RATE STABILITY?

A. Yes. In discussing the possibility of mandatory TOU and seasonal demand rates for general service customers, Mr. Schichtl states "this transition would represent a significant change in rate structure with potentially severe impacts for some customers in this class."[34] In light of these concerns EPE declines proposes this in its present application, choosing instead to more fully analyze such a change.

Q. WHY IS EPE'S DECISION TO DEFER MANDATORY TOU RATES AND SEASONAL DEMAND RATES RELEVANT TO ITS PARTIAL REQUIREMENTS RATE PROPOSAL?

A. It is relevant because it shows a discriminatory intent. Apparently, EPE believes that avoiding potentially "severe impacts" on general service customers is an important rate design consideration, while avoiding similarly severe impacts on DG customers is not. EPE is effectively holding residential DG customers to a different standard than it would other rate classes, highlighting the blatantly discriminatory intent of its DG tariff proposal.

Q. DOES EPE PROPOSE TO UNDERTAKE ANY ACTIONS TO MINIMIZE THE SEVERITY OF IMPACTS THAT THE PROPOSED DG TARIFF WOULD HAVE ON DG CUSTOMERS?

A. No, it does not. There is no hint of any form of gradualism or transition in the utility's DG tariff proposal, nor is there any indication of plans to educate DG

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[33] EPE Exhibit JS-3.
[34] Schichtl Direct, p. 53, lines 25-26, continuing to p. 54, line 1.

customers on the proposed changes, or provide them information or tools to facilitate their ability to manage their electricity bills under the new tariff. To be clear, I do not believe that the proposed DG tariff is reasonable even under a phased-in scenario or in conjunction with additional education efforts. I only raise these possibilities to highlight the total lack of concern EPE displays for the well-being of this small subset of its customers. In this respect, the proposed DG tariff is not only discriminatory; it is also negligent or even intentionally punitive.

F. Volumetric TOU rates and minimum bills are superior rate designs for addressing any identified subsidy

Q. IS EPE'S PROPOSAL TO SUBJECT RESIDENTIAL DG CUSTOMERS TO DEMAND RATES CONSISTENT WITH TRADITIONAL RATE DESIGN FOR RESIDENTIAL CUSTOMERS?

A. No. Mandatory demand rates for residential customers are strongly disfavored both nationally and in Texas. Examples of mandatory demand rates for residential customers or a subset of residential customers are exceedingly rare on a national level. To my knowledge they are unprecedented for Commission-regulated utilities in Texas.

Q. IF IT WERE FOUND THAT RESIDENTIAL DG CUSTOMERS ARE BEING SUBSIDIZED BY OTHER CUSTOMERS, ARE THERE OTHER RATE DESIGN MECHANISMS THAT COULD BE USED TO MITIGATE THIS SUBSIDY?

A. Yes. Though I emphasize that EPE has not shown that such a subsidy exists, I recommend that any identified subsidy be addressed using volumetric TOU rates and/or minimum bills to the greatest extent possible. Both of these designs have significant advantages over fixed charges and demand charges.

Q. PLEASE DESCRIBE WHY VOLUMETRIC TOU RATES ARE SUPERIOR TO DEMAND CHARGES.

A. Properly designed volumetric TOU rates combine the beneficial attributes of volumetric rates—customer familiarity and ability to control—with an improved price or cost causation signal relative to flat volumetric rates. They reward customers for making investments in energy efficiency and reasonable behavioral changes in response to those price signals. Thus, in contrast to demand rates, they send a clear, understandable price signal that the customer can actually consistently react to.

In addition, for the residential class in particular, TOU rates recognize the load diversity of the class as a whole, charging the customer based on their *average* demand during a month, which is more reflective of customer's contribution to cost-causing conditions within the diverse class. For instance, a 2 kWh reading is equivalent to a 2 kW demand for an hour, or a 4 kW demand for 15 minutes and a 1.33 kW demand for the remaining 45 minutes during an hour.

Finally, a volumetric TOU rate retains an equivalent, unambiguous incentive for energy use reduction during peak periods throughout the course of the entire billing period. In this way, it avoids the type of "sunk cost" mentality that I related earlier, whereby a customer who experiences a demand spike early in a billing period will have a greatly diminished conservation incentive for the remainder of the period. Under a volumetric TOU rate, every day is a new day with the same price incentive.

Q. HOW COULD A MINIMUM BILL BE USED TO ADDRESS AN IDENTIFIED SUBSIDY AND WHY IS THIS DESIGN PREFERRABLE TO EPE'S PROPOSAL?

A. A minimum bill rate design guarantees that a customer makes a minimum contribution towards the cost of their service regardless of how much energy they use during a month. A minimum bill is distinct from a fixed charge in that it is only triggered when a customer's bill falls below a designated amount, rather than being imposed regardless of what the customer pays in other charges. In other words, a customer subject to a minimum bill only "pays when they do not pay". Minimum bills applied non-discriminatorily to all customers in a class, whether distributed generation customers or not, guarantee that a customer makes the minimum contribution to their cost of service, regardless of the reason for possible low energy use (DG, energy efficiency, or extended vacation). Minimum bills are superior to fixed charges and demand charges for the following reasons:

- They operate under a simple concept that would be more easily understood by customers than demand charges.
- They better allow the customer to manage their energy bill compared to fixed charges and demand charges, because they allow for bill reductions based on usage characteristics that a customer can actually control. In this respect, they can continue to encourage the customer to conserve energy and/or install DG if properly designed.
- They directly address the issue of DG cost avoidance since they create a minimum payment obligation (i.e., when energy use is low).
- They can ensure that the customer does not pay rates above their cost of service because they are only triggered when the customer avoids payments.

Q. DO ANY OTHER JURISDICTIONS AND UTILITIES EMPLOY MINIMUM BILL MECHANISMS?

A. Yes. I have identified minimum bill mechanisms in the residential tariffs offered by the following utilities, and in the case of Texas, competitive retail providers:

- **Alaska**: Homer Electric Association.
- **California**: Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric (the state's three major investor-owned utilities).

- **Hawaii**: The three collective Hawaiian Electric Company utilities (the state's three investor-owned utilities).
- **Louisiana**: Entergy Louisiana.
- **Maine**: Central Maine Power Company & Bangor Hydro Electric Company (the state's two largest investor-owned utilities)
- **Nebraska**: Omaha Public Power District (the state's largest electric utility)
- **Texas**: Source Power, Hino Electric, Gexa Energy
- **Utah**: Rocky Mountain Power (the state's largest utility and only investor-owned utility)

As a rate design element, residential minimum bills are far more common than residential demand charges, or demand charges placed only on DG customers.

Q. PLEASE SUMMARIZE YOUR THOUGHTS ON HOW EPE'S PARTIAL REQUIREMENTS RATE PROPOSAL ALIGNS WITH TEXAS LAW AND THE PRINCIPLES OF SOUND RATE DESIGN.

A. EPE is seeking a rate design for residential DG customers that places a complete emphasis on maintaining utility revenue while ignoring other ratemaking principles. EPE pays lip service to the principle of basing rates on cost of service, but fails to demonstrate that DG customers do not already pay their full cost of service under the existing rate structure that they know, understand and except. The proposal therefore relies on an unproven assumption to justify the adoption of a rate structure that will be difficult for residential customers to understand, will result in severe rate increases for many customers, and will encourage wasteful use of service. In light of this, it is discriminatory, in violation of both Texas law and traditional principles of rate design. To the extent that a subsidy flowing to DG customers is identified, a rate design that relies on volumetric TOU rates and a minimum bill mechanism could be used to mitigate the issue in a manner that is for more consistent with the law and these principles.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony discusses the numerous reasons that the PUCT should reject EPE's proposal to define a separate class for residential partial requirements customers, and impose a higher fixed charge and demand charges on this class. I explain how EPE's conclusion that DG customers are a separate class of customer is flawed because it relies on an inapt and inaccurate comparison between DG customers and one subset of other residential customers, and in doing so draws a tie that is meaningless. I then explain why EPE's implicit assertion that DG customers do not make payments sufficient to cover their cost of service is not supported by convincing evidence, and how it fails to account for the large suite of benefits that DG can provide to the system. Next, I discuss the merits and drawbacks of EPE's proposed rate design for the partial requirements class and describe the numerous ways in which it departs from accepted principles of ratemaking, resulting in a structure that is unjust and discriminatory for DG customers. Finally, I describe alternative rate designs, volumetric TOU rates and minimum bills, that could be used to mitigate an identified subsidy flowing towards DG customers in a way that is much more consistent with traditional rate design principles and has a much greater precedent than the rate design proposed by EPE.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit JRB-1

Justin R. Barnes

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EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

EXPERIENCE

EQ Research, LLC and **Keyes, Fox & Wiedman, LLP** Cary, North Carolina
Director of Research, July 2015 – present, *Senior Analyst & Research Manager*, March 2013 – July 2015
Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage. Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on state solar market drivers such as net metering, incentives, and renewable portfolio standards. Provide expert witness testimony. Manage the development of a solar power purchase agreement (PPA) toolkit for local governments and the planning and delivery of associated outreach efforts.

North Carolina Solar Center, N.C. State University Raleigh, North Carolina
Senior Policy Analyst, January 2012-May 2013; *Policy Analyst,* September 2007-December 2011
Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States. Managed state-level regulatory tracking for private wind and solar companies. Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets. Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort. Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis. Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies. Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits. Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.

Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. Department of Energy SunShot Solar Outreach Partnership.

Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.

Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. July 2013. For the U.S. Department of Energy SunShot Solar Outreach Partnership.

Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri.* 2013. Case Studies for the U.S. Department of Energy SunShot Solar Outreach Partnership.

Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.

Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.

Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends.* Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.

Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.

Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets.* 2011. American Solar Energy Society Conference Proceedings.

Barnes, J. *SREC Markets: The Murky Side of Solar.* 2011. Article in State and Local Energy Report.

Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY

- Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015.
- South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015.
- South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

Exhibit JRB-2

SOAH DOCKET NO. 473-15-5257
PUC DOCKET NO. 44941

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO	§	OF
CHANGE RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
SUNRUN'S SECOND REQUEST FOR INFORMATION
QUESTION NOS. SUNRUN 2-1 THROUGH SUNRUN 2-33

Sunrun 2-2:

Reference Schichtl Direct testimony: Please (a) identify all data EPE relied on in this case to calculate the "coincidence of the class peak with the system peak" for the proposed Partial Requirements Service Rate Class and (b) explain in detail how EPE used that data to allocate capacity-related costs to that proposed Rate Class, including identification of all cost data and cost allocators shown in EPE's Rate Schedules.

RESPONSE:

(a) Please refer to attachment to EPE's response to OPUC 1-12.
(b) EPE used the sample data to derive the average load and coincident factors for the partial requirements class. The load factor was applied to the class annualized energy to calculate the class Maximum Diversified Demand (MDD). The class Coincident Demand is the product of the class MDD and the average coincident factor. Please see Sunrun 2-002 Attachment for the calculations.

Preparer: Enedina Soto | Title: Economist- Senior

Sponsor: George Novela | Title: Manager- Economic Research

EL PASO ELECTRIC COMPANY
PARTIAL REQUIREMENTS DEMAND CALCULATIONS

Load Study Data

	Jun 2014	Jul 2014	Aug 2014	Sep 2014
Weighted Monthly Energy	1,266.46	1,216.08	963.94	784.64
Weighted Monthly MDD	4.12	3.78	3.15	3.29
Weighted Monthly CD	2.54	1.82	1.89	1.95
Hours	720	744	744	720

Demand Calculations

Annualized Partial Requirements Energy	305,305	511,515	482,429	381,984
Load Factor	0.4274	0.4328	0.4111	0.3312
Maximum Diversified Demand (at Meter)	992	1,589	1,577	1,602
Coincident Factor	0.6160	0.4828	0.5996	0.5933
Coincident Demand (at Meter)	611	767	946	950
Maximum Diversified Demand (at Source)	1,083	1,734	1,722	1,748
Coincident Demand (at Source)	667	837	1,032	1,037
Annual MDD*	1,602			
Diversity Factor	1.67			
NCP (at Meter)	2,678			
NCP (at Source)	2,923			

*The Annual MDD is the Maximum Diversified for the Test Year, for this class the MDD occurred in September.

EL PASO ELECTRIC COMPANY
MONTHLY STRATIFIED DATA
FOR THE TEST YEAR ENDING MARCH 31, 2015

Energy

	Strata 1	Strata 2	Strata 3	Strata 4	Strata 5	Weighted Average
Apr-14	158.77	528.32	438.20	804.32	865.22	486.40
May-14	237.38	734.95	701.93	1,177.55	1,162.16	710.19
Jun-14	480.67	1,440.24	1,270.31	1,822.46	1,977.19	1,266.46
Jul-14	434.93	1,279.86	1,216.72	1,837.40	2,059.28	1,216.08
Aug-14	357.11	1,107.20	954.35	1,238.32	1,707.71	963.94
Sep-14	295.98	916.16	759.51	1,021.04	1,378.14	784.64
Oct-14	219.81	691.25	549.95	776.86	1,036.49	585.03
Nov-14	419.44	530.44	492.52	591.88	920.98	544.96
Dec-14	668.41	615.81	565.20	821.21	1,076.72	694.46
Jan-15	1,042.68	579.24	604.86	897.08	1,093.41	802.48
Feb-15	627.89	434.95	431.91	585.59	754.61	538.49
Mar-15	377.55	527.01	450.95	1,652.72	745.09	643.37

Maximum Demand

	Strata 1	Strata 2	Strata 3	Strata 4	Strata 5	Weighted Average
Apr-14	1.28	3.14	2.15	4.65	4.19	2.27
May-14	1.55	4.67	3.60	5.87	5.43	3.36
Jun-14	2.93	5.76	4.65	6.83	6.90	4.12
Jul-14	1.95	5.28	4.15	7.79	7.11	3.78
Aug-14	1.52	4.17	3.66	4.91	5.44	3.15
Sep-14	2.26	4.16	3.93	5.36	5.71	3.29
Oct-14	1.59	3.79	2.55	5.42	4.26	2.20
Nov-14	2.95	2.37	1.93	2.94	3.28	1.94
Dec-14	2.80	2.33	2.26	4.57	3.32	2.23
Jan-15	4.15	2.02	1.97	3.86	3.38	2.34
Feb-15	2.79	1.96	1.55	3.26	3.15	2.00
Mar-15	2.29	2.84	1.72	18.03	2.76	3.24

Coincident Demand

	Strata 1	Strata 2	Strata 3	Strata 4	Strata 5	Weighted Average
Apr-14	0.06	0.95	0.87	1.47	1.74	0.87
May-14	0.10	2.51	2.27	2.93	2.44	1.89
Jun-14	0.37	2.77	2.64	4.50	4.22	2.54
Jul-14	0.42	2.15	2.04	2.85	2.50	1.82
Aug-14	0.36	2.16	2.08	2.32	3.71	1.89
Sep-14	0.57	2.24	2.14	2.59	3.18	1.95
Oct-14	0.14	1.11	1.44	1.48	1.78	1.09
Nov-14	2.90	1.72	1.22	1.24	2.41	1.88
Dec-14	1.74	1.69	2.09	2.62	2.22	2.00
Jan-15	2.26	1.76	1.56	2.82	2.85	2.09
Feb-15	1.95	1.45	1.13	2.20	2.27	1.68
Mar-15	0.01	0.16	0.39	0.19	1.14	0.30

Load Factor

	Strata 1	Strata 2	Strata 3	Strata 4	Strata 5	Weighted Average
Apr-14	0.1728	0.2340	0.2834	0.2405	0.2866	0.2970
May-14	0.2062	0.2113	0.2621	0.2697	0.2875	0.2837
Jun-14	0.2282	0.3471	0.3798	0.3707	0.3982	0.4274
Jul-14	0.2999	0.3257	0.3942	0.3169	0.3893	0.4328
Aug-14	0.3156	0.3566	0.3505	0.3388	0.4219	0.4111
Sep-14	0.1819	0.3062	0.2685	0.2646	0.3350	0.3312
Oct-14	0.1856	0.2453	0.2897	0.1927	0.3273	0.3579
Nov-14	0.1974	0.3115	0.3553	0.2793	0.3898	0.3900
Dec-14	0.3208	0.3555	0.3358	0.2415	0.4362	0.4190
Jan-15	0.3376	0.3862	0.4127	0.3123	0.4353	0.4616
Feb-15	0.3352	0.3295	0.4157	0.2670	0.3564	0.4013
Mar-15	0.2215	0.2495	0.3531	0.1232	0.3625	0.2671

Coincident Factor

	Strata 1	Strata 2	Strata 3	Strata 4	Strata 5	Weighted Average
Apr-14	0.0453	0.3016	0.4072	0.3173	0.4161	0.3812
May-14	0.0661	0.5371	0.6295	0.5000	0.4495	0.5627
Jun-14	0.1259	0.4809	0.5688	0.6586	0.6121	0.6160
Jul-14	0.2161	0.4062	0.4923	0.3661	0.3510	0.4828
Aug-14	0.2349	0.5179	0.5687	0.4720	0.6819	0.5996
Sep-14	0.2517	0.5383	0.5451	0.4837	0.5572	0.5933
Oct-14	0.0872	0.2944	0.5638	0.2739	0.4176	0.4964
Nov-14	0.9820	0.7265	0.6337	0.4208	0.7340	0.9701
Dec-14	0.6200	0.7257	0.9258	0.5722	0.6700	0.8983
Jan-15	0.5442	0.8738	0.7905	0.7301	0.8440	0.8952
Feb-15	0.7011	0.7398	0.7278	0.6734	0.7207	0.8395
Mar-15	0.0032	0.0579	0.2269	0.0105	0.4120	0.0940

Hours

Apr-14	720
May-14	744
Jun-14	720
Jul-14	744
Aug-14	744
Sep-14	720
Oct-14	744
Nov-14	720
Dec-14	744
Jan-15	744
Feb-15	672
Mar-15	744

Exhibit JRB-3

SOAH DOCKET NO. 473-15-5257
PUC DOCKET NO. 44941

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO	§	OF
CHANGE RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
SUNRUN'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. SUNRUN 1-1 THROUGH SUNRUN 1-50

Sunrun 1-26:

Of the residential customers in EPE's service territory, please provide: (a) the number of those residential DG customers that have installed at least one energy efficiency measure under an EPE energy efficiency program; and, (b) the annual deemed energy savings attributable to the energy efficiency measures installed by those customers.

RESPONSE:

a-b. EPE does not track participation in energy efficiency programs on a per customer basis.

Preparer: Susanne Stone — Title: Manager-Energy Efficiency

Sponsor: James Schichtl — Title: Director-Regulatory Affairs

Exhibit JRB-4

Table 1: Regulatory Investigations with Specific Cost-Benefit Findings

State	Year	Summary of Outcome	Additional Notes
LA	2015	Consultant study found avoided power related costs totaled $73.3M compared to rate-related costs of $75.9M. A COS estimate found that IOU DG customers pay from 52% - 96% of their cost of service.	The methodology used in the study includes both indirect and induced costs and benefits, and incorporated the costs and benefits of the state tax credit. This makes comparisons to other studies difficult because it is hard to isolate the impacts of net metering. The PSC has yet to formally adopt or acknowledge the final consultant study.
ME	2015	Consultant study found a 25-year levelized value of 33.7 cents/kWh for solar DG resources, well above the current retail electricity rate.	A stakeholder process allowing comments on the methodology preceded the consultant study. The study examines both direct energy-related value and societal value.
MA	2014	Consultant study found that net metering would result in a $15.50/MWh and $21.00/MWh *net benefit* to non-participating ratepayers under two different policy scenarios.	The state Solar Task Force commissioned consultants to consider the relative costs and benefits of various policy options, including net metering to achieve two solar adoption goals, from the perspective of participants, non-participating ratepayers, and citizens at large. The study did not aim to calculate the value of solar in MA.
MS	2014	Consultant study found that net metering would have net benefits to all ratepayers in 10 of 11 sensitivity scenarios and a 25-year levelized value of 17 cents/kWh for net metering generation in the base-case scenario.	Subsequent to the completion of the study, the Commission began the process for proposal and adoption of net metering rules after having left the docket dormant for more than 3 years.
MN	2014	Developed a value of solar methodology through a stakeholder process and ultimately calculated a value of solar rate of 14.7 cents/kWh.	The value of solar rate is higher than the average retail rate ~12 cents/kWh for residential customers. No utility has petitioned to adopt a value of solar tariff to replace net metering.
NV	2014	Consultant study found that net metering benefits exceeded costs by $37M over 20 years.	The consultant analysis included the cost of utility provided rebates as a cost, pursuant to statute, thus the costs are higher than for net metering alone. A separate proceeding stemming from 2015 legislation is considering changes to net metering beyond the state cap.
VT	2014	A PSB study found that net metering generation had a 20-year levelized value of 23.7 cents/kWh to ratepayers and 25.6 cents/kWh to society, leading to a conclusion that net metering holds net benefits for both.	The study was developed by staff initially in 2013 and then updated during 2014.
CA	2013	Consultant study found that the total net cost of the NEM program, at full subscription in the year 2020, would be in the range of $1.09B annually projected at 3.1% of the combined IOU revenue requirement. However, it also found that, in aggregate, NEM customers pay amounts close to, an even above, their full cost of service.	This report evaluates the ratepayer impacts of the NEM program as it existed under 2012 rate structures. The reported costs are heavily influenced by the state's inclining tier rate structure, which resulted in net metering offsetting retail rates priced well above cost of service. Newly adopted rate reforms will change this considerably.

Table 2: Regulatory Investigations Without Specific Cost-Benefit Findings

State	Year	Summary of Proceeding
CO	2015	The CO PUC declined to make any changes to net metering or on-site solar generation rules upon the conclusion of an 18-month inquiry. It elected to defer any specific rate proposals to relevant rate proceedings.
AZ	Ongoing	The ACC convened this proceeding in early 2014 subsequent to a petition by Arizona Public Service ("APS") to institute a surcharge on new DG customers. The proceeding was dormant for a year before further proposals to change net metering prompted the Commission to renew its attention to the issue on October 2015. The full scope of the analysis and methodology has not yet been determined.
MT	Ongoing	2015 S.J.R. 12 directed the Interim Energy and Telecommunications Committee to conduct an analysis of the costs and benefits of net metering, and submit a report to the Legislature by September 2016. The joint resolution states that it is "imperative" that costs and benefits be considered prior to making changes to the program.
NY	Ongoing	The Reforming Our Energy Vision ("REV") proceeding involves a much larger set of issues than net metering costs and benefits. A final cost-benefit methodology has not yet been finally adopted. The New York State Energy Research and Development Authority (NYSERDA) is preparing a study on the benefits and costs of net metering.
OR	Ongoing	After the completion of a report on the cost-effectiveness of solar incentives, the Commission convened this proceeding to examine the resource value of solar. A cost benefit methodology has not yet been finally adopted.
UT	Ongoing	This proceeding stems from general rate case proposal by Rocky Mountain Power to institute an additional fixed charge on net metering customers. The Commission found that the utility had failed to meet the evidentiary requirements for such a charge and elected to convene a new proceeding to examine net metering costs and benefits in response. A November 2015 Order defined the bounds of what Rocky Mountain Power must put forth in any rate proposal to subject DG customers to additional charges, providing that the utility must develop two cost of service studies, one which examines system costs with DG customers and one that examines them without DG customers. The comparison of these two scenarios would approximate the "benefits" associated with DG. The cost of service study and the "counterfactual" cost of service study must be filed at the same time or before the utility makes its next general rate case filing.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing instrument has been served on all parties of record in this proceeding on the 11th day of December 2015 by First Class U.S. Mail, postage prepaid, and/or by e-mail through prior agreement, to all parties of record.

Blake Elder

____

Blake Elder
Assistant
Keyes, Fox & Wiedman LLP